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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

[X] Quarterly Report Pursuant to Section 13 or 15(d) of
the Securities Exchange Act of 1934
For the period ended September 30, 2003

OR

[ ] Transition Report Pursuant to Section 13 of 15(d) of
the Securities Exchange Act of 1934
For the transition period from ____ to

Commission file number 0-7246

I.R.S. Employer Identification Number 95-2636730

PETROLEUM DEVELOPMENT CORPORATION
(A Nevada Corporation)
103 East Main Street
Bridgeport, WV 26330
Telephone: (304) 842-6256

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes XX No __

Indicate the number of shares outstanding of each of the issuers classes of common stock, as of the latest practicable date: 15,628,433 shares of the Company's Common Stock ($.01 par value) were outstanding as of September 30, 2003.

Indicate by check mark whether the registrant is an accelerated filer (as definition in Rule 12b-2 of the Exchange Act). Yes XX No __

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

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PART I - FINANCIAL INFORMATION

PART I - FINANCIAL INFORMATION

Independent Auditors' Review Report

The Board of Directors
Petroleum Development Corporation:

We have reviewed the accompanying condensed consolidated balance sheet of Petroleum Development Corporation and subsidiaries as of September 30, 2003, the related condensed consolidated statements of income for the three-month and nine-month periods ended September 30, 2003 and 2002, and the related condensed consolidated statements of cash flows for the nine-month periods ended September 30, 2003 and 2002. These condensed consolidated financial statements are the responsibility of the Company's management.

We conducted our review in accordance with standards established by the American Institute of Certified Public Accountants. A review of interim financial information consists principally of applying analytical review procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with generally accepted auditing standards, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the condensed consolidated financial statements referred to above for them to be in conformity with accounting principles generally accepted in the United States of America.

KPMG LLP

Pittsburgh, Pennsylvania
October 30, 2003

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Balance Sheets
September 30, 2003 and December 31, 2002

ASSETS

	2003 (Unaudited)	2002
Current assets:		
Cash and cash equivalents	$ 40,537,500	$ 51,023,500
Accounts and notes receivable	21,659,500	15,336,500
Inventories	2,111,600	1,174,100
Prepaid expenses	3,958,000	4,125,300
Total current assets	68,266,600	71,659,400
Properties and equipment	241,248,100	195,258,800
Less accumulated depreciation, depletion, and amortization	67,567,300	57,143,700
	173,680,800	138,115,100
Other assets	314,600	2,477,100
	$242,262,000	$212,251,600

(Continued)

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Balance Sheets, Continued
September 30, 2003 and December 31, 2002

LIABILITIES AND STOCKHOLDERS' EQUITY	2003 (Unaudited)	2002
Current liabilities:		
Accounts payable and accrued expenses	$ 31,629,400	$ 28,687,200
Advances for future drilling contracts	17,686,400	37,283,800
Funds held for future distribution	10,550,600	3,917,900
Total current liabilities	59,866,400	69,888,900
Long-term debt	46,000,000	25,000,000
Other liabilities	2,512,000	4,137,200
Deferred income taxes	17,370,000	12,103,300
Asset retirement obligation	698,500	-
Stockholders' equity:		
Common stock	156,300	157,300
Additional paid-in capital	28,573,200	29,316,800
Retained earnings	88,059,700	73,430,100
Accumulated other comprehensive income, net	(974,100)	(1,782,000)
Total stockholders' equity	115,815,100	101,122,200
	$242,262,000	$212,251,600

See accompanying notes to unaudited condensed consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Statements of Income
Three Months and Nine Months ended September 30, 2003 and 2002
(Unaudited)

	Three Months Ended September 30, 2003	Three Months Ended September 30, 2002	Nine Months Ended September 30, 2003	Nine Months Ended September 30, 2002
Revenues:				
Oil and gas well drilling operations	$14,080,100	$ 9,409,800	$47,444,000	$43,834,900
Gas sales from marketing activities	17,686,100	11,672,800	56,644,400	32,116,900
Oil and gas sales	13,088,200	5,140,500	32,866,200	16,012,000
Well operations and pipeline income	1,865,200	1,474,500	5,282,100	4,405,800
Other income	488,300	451,000	1,158,100	1,333,800
	47,207,900	28,148,600	143,394,800	97,703,400
Costs and expenses:				
Cost of oil and gas well drilling operations	11,955,700	8,541,300	39,751,500	37,110,600
Cost of gas marketing activities	17,463,500	11,734,100	55,923,100	32,164,800
Oil and gas production costs	3,986,200	2,158,500	10,303,600	6,433,900
General and administrative expenses	1,377,300	1,069,900	3,741,600	3,073,000
Depreciation, depletion, and amortization	4,243,200	3,123,600	10,632,400	9,083,300
Interest	415,000	399,800	911,000	995,000
	39,440,900	27,027,200	121,263,200	88,860,600
Income before income taxes and cumulative effect of change in accounting principle	7,767,000	1,121,400	22,131,600	8,842,800
Income taxes	2,563,100	232,400	7,303,400	2,602,900
Net income before cumulative effect of change in accounting principle	5,203,900	889,000	14,828,200	6,239,900
Cumulative effect of change in accounting principle (net of taxes of $121,700)	-	-	(198,600)	-
Net income	$5,203,900	$ 889,000	$14,629,600	$ 6,239,900
Basic earnings per common share before accounting change	$0.33	$0.06	$0.94	$0.39
Cumulative effect of change in accounting principle	$ -	$ -	$(0.01)	$ -
Basic earnings per common share	$0.33	$0.06	$0.93	$0.39
Diluted earnings per share before accounting change	$0.31	$0.05	$0.91	$0.38
Cumulative effect of change in accounting principle	$ -	$ -	$(0.01)	-
Diluted earnings per share	$0.31	$0.05	$0.90	$0.38

See accompanying notes to unaudited condensed consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION AND SUBSIDIARIES

Condensed Consolidated Statements of Cash Flows
Nine Months Ended September 30, 2003 and 2002
(Unaudited)

	2003	2002
Cash flows from operating activities:		
Net income	$14,629,600	$ 6,239,900
Adjustments to net income to reconcile to cash used in operating activities:		
Deferred federal income taxes	4,893,200	2,119,400
Depreciation, depletion & amortization	10,632,400	9,083,300
Cumulative effect of change in accounting principle	198,600	-
Accretion of asset retirement obligation	27,000	-
Gain from sale of assets	(144,200)	(10,400)
Leasehold acreage expired or surrendered	1,364,300	595,900
Amortization of stock award	4,100	4,000
Increase in current assets	(7,066,100)	(2,119,700)
Decrease (increase) in other assets	2,087,300	(217,700)
Decrease in current liabilities	(8,746,600)	(26,505,200)
(Decrease) increase in other liabilities	(1,625,200)	445,600
Total adjustments	1,624,800	(16,604,800)
Net provided by (cash used) in operating activities	16,254,400	(10,364,900)
Cash flows from investing activities:		
Capital expenditures	(48,194,500)	(9,293,000)
Proceeds from sale of leases	1,040,800	818,700
Proceeds from sale of fixed assets	162,000	10,400
Net cash used in investing activities	(46,991,700)	(8,463,900)
Cash flows from financing activities:		
Net proceeds from/(retirement of) long-term debt	21,000,000	(1,800,000)
Repurchase and cancellation of treasury stock	(748,700)	(3,616,300)
Net cash provided by (used in) financing activities	20,251,300	(5,416,300)
Net decrease in cash and cash equivalents	(10,486,000)	(24,245,100)
Cash and cash equivalents, beginning of period	51,023,500	48,175,600
Cash and cash equivalents, end of period	$ 40,537,500	$ 23,930,500

See accompanying notes to unaudited condensed consolidated financial statements.

Notes to Condensed Consolidated Financial Statements
September 30, 2003
(Unaudited)

1. Accounting Policies

Reference is hereby made to the Company's Annual Report on Form 10-K for 2002, which contains a summary of significant accounting policies followed by the Company in the preparation of its consolidated financial statements. These policies were also followed in preparing the quarterly report included herein.

2. Stock Compensation

The Company has adopted SFAS No. 123, "Accounting for Stock-Based Compensation," which permits entities to recognize as expense over the vesting period the fair value of all stock-based awards on the date of grant. Alternatively, SFAS 123 allows entities to continue to measure compensation cost for stock-based awards using the intrinsic value based method of accounting prescribed by APB Opinion No. 25, "Accounting for Stock Issued to Employees," and to provide pro forma net income and pro forma earnings per share disclosures as if the fair value based method defined in SFAS 123 had been applied. The Company has elected to continue to apply the provisions of APB 25 and provide the pro forma disclosure provisions of SFAS 123. For stock options granted, the option price was not less than the market value of shares on the grant date, therefore, no compensation cost has been recognized. Had compensation cost been determined under the provisions of SFAS 123, the Company's net income and earnings per share would have been the following on a pro forma basis:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
Net income, as reported	$5,203,900	$ 889,000	$14,629,600	$6,239,900
Deduct total stock-based employee compensation expense determined under fair-value-based method for all rewards, net of tax	-	-	-	-
Pro forma net income	$5,203,900	$ 889,000	$14,629,600	$6,239,900
Pro forma basic earnings per share	$0.33	$0.06	$0.93	$0.39
Pro forma diluted earnings per share	$0.31	$0.05	$0.90	$0.38

3. Basis of Presentation

The Management of the Company believes that all adjustments (consisting of only normal recurring accruals) necessary to a fair statement of the results of such periods have been made. The results of operations for the nine months ended September 30, 2003 are not necessarily indicative of the results to be expected for the full year.

4. Oil and Gas Properties

Oil and Gas Properties are reported on the successful efforts method.

5. Earnings Per Share

Computation of earnings per common and common equivalent share are as follows for the three months and nine months ended September 30:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
Weighted average common shares outstanding	15,636,787	15,734,767	15,670,092	15,910,711
Weighted average common and common equivalent shares outstanding	16,294,616	15,942,015	16,186,849	16,209,376
Net income before cumulative effect of change in accounting principle	$ 5,203,900	$ 889,000	$14,828,200	$6,239,900
Cumulative effect of change in accounting principle (net of taxes of $121,700)	-	-	(198,600)	-
Net income	$5,203,900	$ 889,000	$14,629,600	$6,239,900
Basic earnings per common share before accounting change	$0.33	$0.06	$ 0.94	$0.39
Cumulative effect of change in accounting principle	$ -	$ -	$(0.01)	$ -
Basic earnings per common share	$0.33	$0.06	$ 0.93	$0.39
Diluted earnings per share before accounting change	$0.31	$0.05	$ 0.91	$0.38
Cumulative effect of change in accounting principle	$ -	$ -	$(0.01)	$ -
Diluted earnings per share	$0.31	$0.05	$ 0.90	$0.38

6. Business Segments (Thousands)

PDC's operating activities can be divided into three major segments: drilling and development, natural gas and oil sales, and well operations. The Company drills natural gas and oil wells for Company-sponsored drilling partnerships and purchases an interest in each partnership. The Company also engages in oil and gas sales to utilities, marketing companies, commercial and industrial end-users. The Company charges Company-sponsored partnerships and other third parties competitive industry rates for well operations and gas gathering. Segment information for the three and nine months ended September 30, 2003 and 2002 is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
REVENUES				
Drilling and Development	$14,080	$ 9,410	$47,444	$43,835
Natural Gas and Oil Sales	30,774	16,813	89,511	48,129
Well Operations	1,865	1,475	5,282	4,406
Unallocated amounts (1)	489	451	1,158	1,333
Total	$47,208	$28,149	$143,395	$97,703

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2003	2002	2003	2002
SEGMENT INCOME BEFORE INCOME TAXES				
Drilling and Development	$ 2,124	$ 868	$7,692	$6,724
Natural Gas and Oil Sales	6,305	702	15,999	3,444
Well Operations	721	527	2,172	1,565
Unallocated amounts (2)				
General and Administrative expenses	(1,378)	(1,070)	(3,742)	(3,073)
Interest expense	(415)	(400)	(911)	(995)
Other (1)	410	494	922	1,178
Total	$ 7,767	$ 1,121	$ 22,132	$ 8,843

	September 30, 2003	December 31, 2002
SEGMENT ASSETS		
Drilling and Development	$ 30,099	$ 31,279
Natural Gas Sales	192,738	162,232
Well Operations	10,838	10,706
Unallocated amounts		
Cash	519	1,736
Other	8,068	6,299
Total	$242,262	$212,252

(1) Includes interest on investments and partnership management fees which are not allocated in assessing segment performance.

(2) Items which are not allocated in assessing segment performance.

7. Comprehensive Income

Comprehensive income includes net income and certain items recorded directly to shareholders' equity and classified as Other Comprehensive Income. The following table illustrates the calculation of comprehensive income for the nine months ended September 30, 2003 and 2002.

	2003	2002
Net Income before cumulative effect of change in accounting principle	$ 14,828,200	$6,239,900
Cumulative effect on prior years of SFAS 143 - "Accounting for Asset Retirement Obligations" (net of taxes of $121,700)	(198,600)	-
Net income	14,629,600	6,239,900
Other Comprehensive Income (loss) (net of tax):		
Reclassification adjustment for settled contracts included in net income (net of tax of $603,200 and $49,500, respectively)	984,100	(80,800)
Change in fair value of outstanding hedging positions (net of tax of $108,000 and $230,000, respectively)	(176,200)	(375,300)
Other Comprehensive Income (loss)	807,900	(456,100)
Comprehensive Income	$15,437,500	$5,783,800

8. Commitments and Contingencies

The nature of the independent oil and gas industry involves a dependence on outside investor drilling capital and involves a concentration of gas sales to a few customers. The Company sells natural gas to various public utilities, natural gas marketers, industrial and commercial customers.

The Company would be exposed to natural gas price fluctuations on underlying purchase and sale contracts should the counterparties to the Company's hedging instruments or the counterparties to the Company's gas marketing contracts not perform. Such nonperformance is not anticipated. There were no counterparty default losses in 2003 or 2002.

Substantially all of the Company's drilling programs contain a repurchase provision where Investors may request the Company to repurchase their partnership units at any time beginning with the third anniversary of the first cash distribution. The provision provides that the Company is obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions), only if investors request the Company to repurchase such units, subject to the Company's financial ability to do so. The maximum annual 10% repurchase obligation, if requested by investors, is currently approximately $4.2 million. The Company has adequate liquidity to meet this obligation.

The Company is not party to any legal action that would materially affect the Company's results of operations or financial condition.

9. Common Stock Repurchase

On March 13, 2003 the Company publicly announced the authorization by its Board of Directors to repurchase up to 5% of the Company's common stock (785,000 shares) at fair market value at the date of purchase. Under the program, the Board has discretion as to the dates of purchase and amounts of stock to be purchased and whether or not to make purchases. This program is scheduled to expire on December 31, 2004. The following activity has occurred since inception of the plan on March 13, 2003 until September 30, 2003.

Month of Purchase	March, 2003	April, 2003	September, 2003
Average Price paid per share	$6.08	$6.48	$11.15
Broker/Dealer	McDonald Investments	McDonald Investments	McDonald Investments
Number of Shares Purchased	46,500	49,900	12,800
Remaining Number of Shares to Purchase	738,500	688,600	675,800

10. Change in Accounting Principle

In June 2001, the Financial Accounting Standard Board issued SFAS No. 143, "Accounting for Asset Retirement Obligations" that requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. This statement is effective for fiscal years beginning after June 15, 2002. The Company adopted SFAS No. 143 on January 1, 2003 and recorded a net asset of $271,800 and a related liability of $592,100 (using a 6% discount rate) and a cumulative effect on change in accounting principle on prior years of $198,600 (net of taxes of $121,700).

11. Acquisition of Oil and Gas Properties

During the second quarter of 2003 the Company completed the purchase of natural gas properties in the Denver-Julesburg Basin in northeastern Colorado for $28 million from Williams Production RMT Company, a subsidiary of The Williams Companies, Inc. of Tulsa, OK. The effective date of the purchase was April 1, 2003. Funding for the acquisition was provided from the Company's bank credit facility with Bank One N.A. and BNP Paribas.

The Company estimates the acquisition included approximately 22.6 billion cubic feet (Bcf) of proved developed producing (PDP) and 3.4 Bcf of proved developed non-producing reserves (PDNP) from 166 wells. All of the reserves are natural gas. The acquired property may also include up to 150 additional locations, subject to approval of revised spacing from the State of Colorado. The estimated PDNP reserves are expected to be available through the use of additional equipment to remove produced water from wells, a technique that the Company has already proven successful in a number of the wells purchased.

12. Subsequent Event - Commitments and Contingencies

On October 3, 2003 the Company's Executive Vice President and Chief Financial Officer, Dale G. Rettinger, passed away. The Company had a stock redemption agreement with Mr. Rettinger which required the Company to maintain a life insurance policy on Mr. Rettinger in the amount of $1 million. At the election of his estate made within one year of his death, the Company must utilize the proceeds from the insurance policy to purchase from his estate all or a portion of his shares of the Company's Common Stock owned by him, including shares subject to outstanding stock options owned by him at the time of his death, up to an aggregate purchase price of $1 million. The purchase price for such shares of Common Stock will be based upon the average closing "Ask" price for the Company's Common Stock as quoted by Nasdaq during the preceeding 90 calendar day period. As of this date no purchase request has been made by Mr. Rettinger's estate and no shares or options have been purchased by the Company. In addition, under the terms of Mr. Rettinger's employment contract, the Company is obligated to pay Mr. Rettinger's estate a death benefit of approximately $850,000.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Results of Operations

Three Months Ended September 30, 2003 Compared with September 30, 2002

Revenues. Total revenues for the three months ended September 30, 2003 were $47.2 million compared to $28.1 million for the three months ended September 30, 2002, an increase of approximately $19.1 million, or 68.0 percent. Such increase was a result of increased drilling revenues, sales from gas marketing activities, oil and gas sales and well operations and pipeline income. Drilling revenues for the three months ended September 30, 2003 were $14.1 million compared to $9.4 million for the three months ended September 30, 2002, an increase of approximately $4.7 million or 50.0 percent. Such increase was due to the drilling backlog at June 30, 2003 along with the early closing of the fully subscribed PDC 2003-B Partnership. Natural gas sales from the marketing activities of Riley Natural Gas (RNG), the Company's marketing subsidiary for the three months ended September 30, 2003 were $17.7 million compared to $11.7 million for the three months ended September 30, 2002, an increase of approximately $6.0 million or 51.3 percent. Such increase was due to natural gas sold at higher average sales prices offset in part by lower volumes sold. Oil and gas sales from the Company's producing properties for the three months ended September 30, 2003 were $13.1 million compared to $5.1 million for the three months ended September 30, 2002, an increase of $8.0 million or 156.9 percent. The increase was due to significantly increased volumes sold at substantially higher average sales prices of oil and natural gas. The volume of natural gas sold for the three months ended September 30, 2003 was 2.4 million Mcf at an average sales price of $4.55 per Mcf compared to 1.6 million Mcf at an average sales price of $2.35 per Mcf for the three months ended September 30, 2002. Oil sales were 80,000 barrels at an average sales price of $28.42 per barrel for the three months ended September 30, 2003 compared to 51,000 barrels at an average sales price of $26.39 per barrel for the three months ended September 30, 2002. The increase in natural gas volumes was the result of the Company's increased investment in oil and gas properties, primarily the Williams property acquisition, effective April 1, 2003, recompletions of existing wells and the Company's additional investment in wells drilled along with the PDC

2003-A Partnership. Financial results depend upon many factors, particularly the price of natural gas and our ability to market our production on economically attractive terms. Price volatility in the natural gas market has remained prevalent in the last few years. Natural gas prices declined dramatically at the end of 2001 and during the entire first quarter of 2002. However, in the second quarter of 2002, the Company saw a significant strengthening of natural gas prices in its Appalachian and Michigan producing areas. Natural gas prices in Colorado remained low for most of 2002. In the fourth quarter of 2002 and continuing in 2003, Colorado prices began to increase, although they continue to trail prices in other areas. The Company believes the lower prices in the Rocky Mountain Region, including Colorado, resulted from increasing local supplies that exceeded the local demand and pipeline capacity available to move gas from the region. On May 1st of 2003, the Kern River pipeline expansion was completed and placed into service. The Kern River Pipeline Company has announced that the additional facilities added about 900 million cubic feet per day of capacity for deliveries to Arizona, Nevada and southern California. This represents almost 30% of the prior pipeline capacity from the region to the West Coast and other markets outside the region. The Company believes that the completion and start-up of the pipeline eliminated or reduced the local supply surplus, leading to improved natural gas prices in the region. Since the startup of the new Kern River pipeline the Colorado Interstate Gas price index has improved to a range of from 83% to over 90% of the NYMEX price, levels consistent with historical price relationships before the recent local demand/pipeline capacity problem. The Company has commodity price hedging contracts for production from October 2003 through December 2004 to protect against possible short-term price weaknesses.

Well operations and pipeline income for the three months ended September 30, 2003 was $1.9 million compared to $1.5 million for the three months ended September 30, 2002, an increase of approximately $400,000 or 26.7 percent. Such increase was due to an increase in the number of wells and pipelines operated by the Company. Other income for the three months ended September 30, 2003 was $488,000 compared to $451,000 for the three months ended September 30, 2002.

Production by area of operations:

	Three Months Ended September 30, 2003			Three Months Ended September 30, 2002		
	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)
Appalachian Basin	1,121	485,968	492,694	1,145	525,531	532,401
Michigan Basin	1,616	449,457	459,153	1,887	528,906	540,228
Rocky Mountains	77,367	1,442,556	1,906,758	47,518	566,510	851,618
Total	80,104	2,377,981	2,858,605	50,550	1,620,947	1,924,247
Average Price	$28.42	$4.55	$4.58	$26.39	$2.35	$2.67

Costs and expenses. Costs and expenses for the three months ended September 30, 2003 were $39.4 million compared to $27.0 million for the three months ended September 30, 2002, an increase of approximately $12.4 million or 45.9 percent. Such increase was primarily the result of increased cost of oil and gas well drilling operations, gas purchased for gas marketing activities, and oil and gas production costs. Oil and gas well drilling operations costs for the three months ended September 30, 2003 were $12.0 million compared to $8.5 million for the three months ended September 30, 2002, an increase of approximately $3.5 million or 41.1 percent. Such increase was due to the higher levels of drilling referred to above. The cost of gas marketing activities for the three months ended September 30, 2003 were $17.5 million compared to $11.7 million for the three months ended September 30, 2002, an increase of $5.8 million or 49.6 percent. The increase was due to the significantly higher average prices of natural gas purchased and offset in part by slightly lower volumes. Based on the nature of the Company's gas marketing activities, hedging did not have a significant impact on the Company's net margins from marketing activities during either period. Oil and gas production costs from the Company's producing properties for the three months ended September 30, 2003 were $4.0 million compared to $2.2 million for the three months ended September 30, 2002, an increase of approximately $1.8 million or 81.8% percent. Such increase was due to the increased production costs and severance and property taxes on the increased volumes and higher sales prices of natural gas and oil sold, along with the increased number of wells and pipelines operated by the Company. General and administrative expenses for the three months ended September 30, 2003 increased to $1.4 million compared with $1.1 million for the three months ended September 30, 2002.

Depreciation, depletion, and amortization costs for the three months ended September 30, 2003 increased to $4.2 million from approximately $3.1 million for the three months ended September 30, 2002. The increase was due to the significantly increased production and investment in oil and gas properties by the Company as referred to above. Interest costs for the three months ended September 30, 2003 were $415,000 compared to $400,000 for the three months ended September 30, 2002.

Net income. Net income for the three months ended September 30, 2003 was $5.2 million compared to a net income of $900,000 for the three months ended September 30, 2002, an increase of approximately $4.3 million.

Nine Months Ended September 30, 2003 Compared with September 30, 2002

Revenues. Total revenues for the nine months ended September 30, 2003 were $143.4 million compared to $97.7 million for the nine months ended September 30, 2002, an increase of approximately $45.7 million, or 46.8 percent. Such increase was a result of increased drilling revenues, sales from gas marketing activities, oil and gas sales and well operations and pipeline income. Drilling revenues for the nine months ended September 30, 2003 were $47.4 million compared to $43.8 million for the nine months ended September 30, 2002, an increase of approximately $3.6 million or 8.2 percent. Such increase was due to increased volume of drilling activity by the Company's drilling programs. Natural gas sales from the marketing activities of Riley Natural Gas (RNG), the Company's marketing subsidiary for the nine months ended September 30, 2003 were $56.6 million compared to $32.1 million for the nine months ended September 30, 2002, an increase of approximately $24.5 million or 76.3 percent. Such increase was due to natural gas sold at significantly higher average sales prices offset in part by lower volumes sold. Oil and gas sales from the Company's producing properties for the nine months ended September 30, 2003 were $32.9 million compared to $16.0 million for the nine months ended September 30, 2002, an increase of $16.9 million or 105.6 percent. The increase was due to significantly increased volumes sold at substantially higher average sales prices of oil and natural gas. The volume of natural gas sold for the nine months ended September 30, 2003 was 6.1 million Mcf at an average sales price of $4.46 per Mcf compared to 4.8 million Mcf at an average sales price of $2.49 per Mcf for the nine months ended September 30, 2002. Oil sales were 195,000 barrels at an average sales price of $28.05 per barrel for the nine months ended September 30, 2002 compared to 175,000 barrels at an average sales price of $22.89 per barrel for the nine months ended September 30, 2002. The increase in natural gas volumes was the result of the Company's increased investment in oil and gas properties, primarily the Williams property acquisition, effective April 1, 2003, recompletions of existing wells and the Company's additional investment in wells drilled along with the PDC 2003-A Partnership. Financial results depend upon many factors, particularly the price of natural gas and our ability to market our production on economically attractive terms. Price volatility in the natural gas market has remained prevalent in the last few years. Natural gas prices declined dramatically at the end of 2001 and during the entire first quarter of 2002. However, in the second quarter of 2002, the Company saw a significant strengthening of natural gas prices in its Appalachian and Michigan producing areas. Natural gas prices in Colorado remained low for most of 2002. In the fourth quarter of 2002 and continuing in 2003, Colorado prices began to increase, although they continue to trail prices in other areas. The Company believes the lower prices in the Rocky Mountain Region, including Colorado, resulted from increasing local supplies that exceeded the local demand and pipeline capacity available to move gas from the region. On May 1st of 2003, the Kern River pipeline expansion was completed and placed into service. The Kern River Pipeline Company has announced that the additional facilities added about 900 million cubic feet per day of capacity for deliveries to Arizona, Nevada and southern California. This represents almost 30% of the prior pipeline capacity from the region to the West Coast and other markets outside the region. The Company believes that the completion and start-up of the pipeline eliminated or reduced the local supply surplus, leading to improved natural gas prices in the region. Since startup of the new Kern River pipeline the Colorado Interstate Gas price index has improved to a range of from 83% to over 90% of the NYMEX price, levels consistent with historical price relationships before the recent local demand/pipeline capacity problem. The Company has commodity price hedging contracts for production from October 2003 through December 2004 to protect against possible short-term price weaknesses.

Well operations and pipeline income for the nine months ended September 30, 2003 was $5.3 million compared to $4.4 million for the nine months ended September 30, 2002, an increase of approximately $900,000 or 20.5 percent. Such increase was due to an increase in the number of wells and pipelines operated by the Company. Other income for the nine months ended September 30, 2003 was $1.2 million compared to $1.3 million for the nine months ended September 30, 2002.

Production by area of operations:

	Nine Months Ended September 30, 2003			Nine Months Ended September 30, 2002		
	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Equivalents (Mcfe)
Appalachian Basin	3,135	1,459,414	1,478,224	3,873	1,573,698	1,596,936
Michigan Basin	4,910	1,382,532	1,411,992	6,492	1,638,702	1,677,654
Rocky Mountains	187,194	3,297,830	4,420,994	164,405	1,604,875	2,591,305
Total	195,239	6,139,776	7,311,210	174,770	4,817,275	5,865,895
Average Price	$28.05	$4.46	$4.50	$22.89	$2.49	$2.73

Costs and expenses. Costs and expenses for the nine months ended September 30, 2003 were $121.3 million compared to $88.9 million for the nine months ended September 30, 2002, an increase of approximately $32.4 million or 36.4 percent. Such increase was primarily the result of increased cost of oil and gas well drilling operations, gas purchased for gas marketing activities and oil and gas production costs. Oil and gas well drilling operations costs for the nine months ended September 30, 2003 were $39.8 million compared to $37.1 million for the nine months ended September 30, 2002, an increase of approximately $2.7 million or 7.3 percent. Such increase was due to the higher levels of drilling volumes referred to above. The cost of gas marketing activities for the nine months ended September 30, 2003 were $55.9 million compared to $32.2 million for the nine months ended September 30, 2002, an increase of $23.7 million or 73.6 percent. The increase was due to the significantly higher average purchase prices of natural gas purchased and marketed offset in part by slightly lower volumes purchased for resale. Based on the nature of the Company's gas marketing activities, hedging did not have a significant impact on the Company's net margins from marketing activities during either period. Oil and gas production costs from the Company's producing properties for the nine months ended September 30, 2003 were $10.3 million compared to $6.4 million for the nine months ended September 30, 2002, an increase of approximately $3.9 million or 60.9 percent. Such increase was due to the increased production costs and severance and property taxes on the significantly increased volumes and higher average sales prices of natural gas and oil sold along with the increased number of wells and pipelines operated by the Company. General and administrative expenses for the nine months ended September 30, 2003 increased to $3.7 million compared with $3.1 million for the nine months ended September 30, 2002 an increase of approximately $600,000 or 19.4 percent. Depreciation, depletion, and amortization costs for the nine months ended September 30, 2003 increased to $10.6 million from approximately $9.1 million for the nine months ended September 30, 2002 an increase of approximately $1.5 million or 16.5 percent. . The increase was due to the significantly increased production and investment in oil and gas properties by the Company as referred to above. Interest costs for the nine months ended September 30, 2003 were $911,000 compared to $995,000 for the nine months ended September 30, 2002.

Change in Accounting Principle. The Company adopted SFAS No. 143 *"Accounting for Asset Retirement Obligations"* on January 1, 2003 and booked the cumulative effect on prior years of $198,600 (net of taxes of $121,700).

Net income. Net income for the nine months ended September 30, 2003 was $14.6 million compared to a net income of $6.2 million for the nine months ended September 30, 2002, an increase of approximately $8.4 million or 135.5 percent.

Liquidity and Capital Resources

The Company funds its operations through a combination of cash flow from operations, capital raised through drilling partnerships, and use of the Company's credit facility. Operational cash flow is generated by sales of natural gas from the Company's well interests, well drilling and operating activities for the Company's investor partners, natural gas gathering and transportation, and natural gas marketing. Cash payments from Company-sponsored partnerships are used to drill and complete wells for the partnerships, with operating cash flow accruing to the Company to the extent payments exceed drilling costs. The Company utilizes its revolving credit arrangement to meet the cash flow requirements of its operating and investment activities.

Natural gas and oil prices have been unusually volatile for the past few years, and the Company anticipates continued volatility in the future. Currently, the NYMEX futures reflect a market expectation of gas prices at Henry Hub close to or above record prices per million Btu's (Mmbtu). These prices look strong for the remainder of the year although natural gas storage levels are near normal levels following a period when storage levels had been at a five-year low. The Company believes this situation creates the possibility of both periods of low prices and continued high prices.

In 2001, 2002 and earlier this year Colorado gas prices were adversely affected by an increase in the negative "basis" between NYMEX and Colorado prices. In the past, natural gas produced by the Company in Colorado has sold for 10-20% less than the Company's prices received in the Michigan and Appalachian basins, but the Company's Colorado development costs have been less than the costs per Mcfe of development in the Michigan and Appalachian basins. Pipeline capacity from the area to major markets in California and the Midwest was not adequate to move the new supplies developed over the past several years by oil and gas companies when local demand was at low summer levels. The result was lower prices and some limited curtailment of production during the summer months. Higher winter demand by local Rocky Mountain markets improved gas prices during the first three quarters of 2003, and the recent start-up of the Kern River Pipeline expansion project has reduced the price discount to historical levels. Several other pipeline projects are underway and in planning stages that will improve capacity over the next several years. There remains a possibility of greater seasonal volatility in Colorado than some other producing areas, but we expect the situation to continue to be better for the remainder of 2003 than it was in 2002.

Because of the uncertainty surrounding natural gas prices we have used various hedging instruments to manage some of the impact of fluctuations in prices. Through December of 2004 we have in place a series of floors and ceilings on part of our natural gas production. Under the arrangements, if the applicable index rises above the ceiling price, we pay the counterparty, however if the index drops below the floor the counterparty pays us. During the three months ended September 30, 2003 the Company averaged natural gas volumes sold of 792,700 Mcf per month and oil sales of 26,700 barrels per month. The positions in effect as of September 30, 2003 on the Company's share of production are shown in the following table:

	Floors		Ceilings	
Month	Monthly Quantity Mmbtu	Contract Price	Monthly Quantity Mmbtu	Contract Price
NYMEX Based Hedges - (Appalachian and Michigan Basins)				
Oct 2003	114,000	$3.40	57,000	$3.80
	122,000	$4.50	122,000	$5.30
	114,000	$4.25		
Nov 2003	114,000	$4.30	57,000	$5.20
Dec 2003	114,000	$4.45	57,000	$5.30
Jan 2004	114,000	$4.45	57,000	$5.40
Feb 2004	114,000	$4.30	57,000	$5.25
Mar 2004	114,000	$4.20	57,000	$5.00
Apr 2004 - Oct 2004	81,000	$4.00	81,000	$5.65

Colorado Interstate Gas (CIG) Based Hedges (Piceance Basin)				
Oct 2003	32,000	$2.50	8,000	$3.13
Nov 2003 - Mar 2004	20,000	$3.50	20,000	$5.255
Apr 2004 - Oct 2004	25,000	$3.20	25,000	$4.70
NYMEX Based Hedges (Williams acquisition)				
Oct 2003 - Dec 2004	150,000	$4.50		

The Company hedges prices for its partners' share of production as well as its own production. Only the Company's share of hedging is reflected in the proceeding table and in this narrative. Actual wellhead prices will vary based on local contract conditions, gathering and other costs and factors.

Oil prices have softened from earlier in the year. While oil prices are influenced by supply and demand, global geopolitics may be the single most important determinant. Since the percentage of the Company's production reflected by oil sales has increased to 17%, variations in oil prices will have a greater impact on the Company than in the past. The Company also has in place as of September 30, 2003 hedges on 4,800 barrels a month for its Wattenburg Field oil production for the period from October 2003 through December 2003 at a price of $30.00 per barrel.

The Company plans to conduct all of its 2003 drilling operations in Colorado. If future planned pipeline capacity increases do not occur, it could reduce the Company's results from its producing activities. It could also make the Company's drilling programs less attractive to potential investors. However, the Rocky Mountain region is the only onshore area of the U.S. with increasing production. The Company believes the necessary pipelines will be constructed, so increasing Rocky Mountain gas can move to the markets where it will be needed.

The Company closed its second drilling program of 2003 in September, 2003 and started the drilling of the wells during the third quarter with the remainder to be drilled in the fourth quarter 2003. This second drilling program of 2003 closed early after being fully subscribed with subscriptions of $17.5 million compared to the second program of 2002 which closed with subscriptions of $11.2 million. The third drilling program of 2003 the PDC 2003-C Partnership will close early during the first week of November at the maximum investor subscriptions of $17.5 million compared with the third program of 2002 which closed with subscriptions of $9.4 million. The fourth drilling program of 2003 the PDC 2003-D is scheduled to close on December 31, 2003 and has a maximum allowable subscriptions of $35 million. The Company generally invests, as its equity contribution to each drilling partnership, an additional sum of 21.75% of the aggregate subscriptions received for that particular drilling partnership. As a result, the Company is subject to substantial cash commitments at the closing of each drilling partnership. The funds received from these programs are restricted to use in future drilling operations. No assurance can be made that the Company will continue to receive this level of funding from these or future programs.

Substantially all of the Company's drilling programs contain a repurchase provision where Investors may request the Company to repurchase their partnership units at any time beginning with the third anniversary of the first cash distribution. The provision provides that the Company is obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions), only if investors request the Company to repurchase such units subject to the Company's financial ability to do so. The maximum annual 10% repurchase obligation, if requested by the investors, is currently approximately $4.2 million. The Company has adequate liquidity to meet this obligation. During 2003 the Company has spent $200,600 under this provision.

On March 13, 2003 the Company publicly announced a common stock repurchase program to repurchase up to 5% of the Company's outstanding common stock (785,000 shares) expiring on December 31, 2004. From inception of the program until September 30, 2003, the Company has repurchased 109,200 shares at an average price of $7.90 per share. The Company intends to fund this repurchase of common stock through internally generated cash flow.

The Company has a credit facility with Bank One, NA and BNP Paribas of $100 million subject to adequate oil and natural gas reserves. The current borrowing base is $80.0 million, of which the Company has activated $50.0 million of the facility. As of September 30, 2003, the outstanding balance on the line of credit was $46.0 million of which $10.0 million was subject to an interest rate swap at a rate of 8.39% , $24.0 million at a LIBOR rate of 2.62% and the remaining $12.0 million was subject to a prime rate of 4.00%. The line of credit is at prime, with LIBOR alternatives available at the discretion of the Company. No principal payments are required until the credit agreement expires on July 3, 2005.

A summary of Company's contractual obligations and due dates are as follows:

		Payments due by period			
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-Term Debt	$46,000,000	-	$46,000,000	-	-
Operating Leases	1,125,800	$594,900	367,900	$163,000	-
Asset Retirement Obligation	698,500	-	50,000	50,000	$598,500
Other Liabilities	2,512,000	100,000	200,000	200,000	2,012,000
Total	$50,336,300	$694,900	$46,617,900	$413,000	$2,610,500

The Company continues to pursue capital investment opportunities in producing natural gas properties as well as its plan to participate in its sponsored natural gas drilling partnerships, while pursuing opportunities for operating improvements and costs efficiencies. Management believes that the Company has adequate capital to meet its operating requirements.

Critical Accounting Policies

Certain accounting policies are very important to the portrayal of Company's financial condition and results of operations and require management's most subjective or complex judgments. The policies are as follows:

Revenue Recognition

Oil and gas wells are drilled primarily on a contract basis. The Company follows the percentage-of-completion method of income recognition for drilling operations in progress.

Sales of natural gas are recognized when sold, oil revenues are recognized when produced into a stock tank.

Well operations income consists of operation charges for well upkeep, maintenance and operating lease income on tangible well equipment.

Valuation of Accounts Receivable

Management reviews accounts receivable to determine which are doubtful of collection. In making the determination of the appropriate allowance for doubtful accounts, management considers the Company's history of write-offs, relationships and overall credit worthiness of its customers, and well production data for receivables related to well operations.

Impairment of Long-Lived Assets

Exploration and development costs are accounted for by the successful efforts method.

The Company assesses impairment of capitalized costs of proved oil and gas properties by comparing net capitalized costs to undiscounted future net cash flows on a field-by-field basis using expected prices. Prices utilized in each year's calculation for measurement purposes and expected costs are held constant throughout the estimated life of the properties. If net capitalized costs exceed undiscounted future net cash flow, the measurement of impairment is based on estimated fair value which would consider future discounted cash flows.

Unproved properties are assessed on a property-by-property basis and properties considered to be impaired are charged to expense when such impairment is deemed to have occurred.

Deferred Tax Asset Valuation Allowance

Deferred tax assets are recognized for deductible temporary differences, net operating loss carry-forwards, and credit carry-forwards if it is more likely than not that the tax benefits will be realized. To the extent a deferred tax asset cannot be recognized under the preceding criteria, a valuation allowance has been established.

The judgments used in applying the above policies are based on management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results may differ from those estimates. See additional discussions in this Management's Discussion and Analysis.

New Accounting Standards

In December 2002, the FASB issued SFAS 148, Accounting for Stock-Based Compensation - Transition and Disclosure, an amendment of FASB Statement No. 123. This statement amends SFAS No. 123, Accounting for Stock-Based Compensation, to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, this statement amends the disclosure requirements of SFAS 123 to require prominent disclosures in both annual and interim financial statements. Certain of the disclosure modifications are required for interim periods beginning after ending December 15, 2002 and are included in the notes to these condensed financial statements.

A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141 and SFAS no. 142 to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires registrants to classify the costs mineral rights associated with extracting oil and gas intangible assets in the balance sheets, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, the Company has included the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties. If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify costs of mineral rights associated with extracting oil and gas as a separate intangible assets line item on the balance sheet, the Company would be required to reclassify the historical cost of approximately $5,169,000 and $4,208,800 of mineral rights associated with undeveloped oil and gas properties and $12,335,900 and $10,898,700 of mineral rights associated with developed oil and gas properties as of September 30, 2003 and December 31, 2002, respectively, out of oil and gas properties and into a separate intangible mineral rights assets line item. The Company's total balance sheet, cash flows and results of operations would be not affected since such intangible assets would continue to be amortized and assessed for impairment.

The reclassification of these amounts would not affect the method in which such costs are amortized or the manner in which the Company assesses impairment of capitalized costs. As a result, net income would not be affected by the reclassification.

Item 3. Quantitative and Qualitative Disclosure About Market Rate Risk

Interest Rate Risk

There have been no material changes in the reported market risks faced by the Company since December 31, 2002.

Commodity Price Risk

The Company utilizes commodity-based derivative instruments as hedges to manage a portion of its exposure to price risk from its natural gas sales and marketing activities. These instruments consist of NYMEX and Colorado Interstate-traded natural gas futures contracts and option contracts. These hedging arrangements have the effect of locking in for specified periods (at predetermined prices or ranges of prices) the prices the Company will receive for the volume to which the hedge relates. As a result, while these hedging arrangements are structured to reduce the Company's exposure to decreases in price associated with the hedging commodity, they also limit the benefit the Company might otherwise have received from price increases associated with the hedged commodity. The Company's policy prohibits the use of natural gas future and option contracts for speculative purposes. As of September 30, 2003, PDC had entered into a series of natural gas future contracts and options contracts. The fair value of these floors and ceilings as of September 30, 2003 is ($24,500). Open future contracts maturing in 2003-2005 are for the sale of 2,790,000 Mmbtu of natural gas with a weighted average price of $4.43 Mmbtu resulting in a total contract amount of $12,361,500, and a fair market value of $(1,046,100). Open option contracts are for the sale of 400,800 Mmbtu of natural gas with an average ceiling price of $5.18 and for the sale of 2,946,900 Mmbtu of natural gas with an average floor price of $4.40 and a fair market value of ($24,500).

Item 4. Controls and Procedures

Under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer and Chief Financial Officer, the Company has evaluated the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Exchange Act Rule 13a-14(c)) as of the end of this fiscal quarter, and, based on their evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that these disclosure controls and procedures are effective in all material respects, including those to ensure that information required to be disclosed in reports filed or submitted under the Securities Exchange Act is recorded, processed, summarized, and reported, within the time periods specified in the Commission's rules and forms, and is accumulated and communicated to management, including the Company's Chief Executive Officer and Chief Financial Officer, as appropriate to allow for timely disclosure. There have been no significant changes in our internal control over financial reporting or in other factors that have materially affected or are reasonably likely to materially affect these controls that occurred during the Company's last fiscal quarter.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings

The Company is not a party to any legal actions that would materially affect the Company's operations or financial statements.

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits

Exhibit Name	Exhibit Number	
Articles of Incorporation	3.1	Incorporated by reference to Exhibit 3.1 of Form S-2 filed September 25, 1997, SEC File Number 333-36369
By Laws	3.2	Incorporated by reference to Exhibit 3.2 of Form 8-K filed on January 24, 2003
Rule 13a-14(a)/15d-14(a) Certifications by Chief Executive Officer	31	
Rule 13a-14(a)/15d-14(a)Certification by Chief Financial Officer	31	
Section 1350 Certifications by Chief Executive Officer	32	
Section 1350 Certifications by Chief Financial Officer	32	

(b) Reports on Form 8-K during the quarter ended September 30, 2003

Form 8-K current report dated August 4, 2003, under Item 5. "Other Matters" the Company issued a news release announcing 2nd quarter 2003 earnings.

Form 8-K current report dated September 5, 2003, under Item 5. "Other Matters", the Company issued a news release announcing the closing of its PDC 2003-B Drilling Partnership.

Form 8-K current report dated September 30, 2003, under Item 5. "Other Matters", the Company issued a news release announcing reporting that it will post updates on the corporate website regarding a presentation by the President, Steven R. Williams and it will begin reporting the amount of subscription sales from its drilling partnerships on a periodic basis.

Form 8-K current report dated October 6, 2003, under Item 5. "Other Matters", the Company issued a news release announcing the passing of Dale G Rettinger, Executive Vice President and Chief Financial Officer and that Darwin L. Stump, the Company's controller, has been named as acting CFO.

Form 8-K current report dated October 22, 2003, under Item 5. "Other Matters" the Company issued a news release announcing its upcoming third quarter earnings release on November 3rd and upcoming conference call to discuss earnings on November 4th.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934 the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Petroleum Development Corporation
(Registrant)

Date: November 4, 2003

/s/ James N. Ryan
James N. Ryan
Chief Executive Officer

Date: November 4, 2003

/s/ Steven R. Williams
Steven R. Williams
President

Date: November 4, 2003

/s/ Darwin L. Stump
Darwin L. Stump
Acting Chief Financial Officer